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Energy Procedia 37 (2013) 7039 – 7045
Energy Procedia

GHGT-11

Selection of optimal CO_2 capture plant capacity for better investment decisions

R. Anantharaman[a,*], S. Roussanaly[a], S.F. Westman[a] and J. Husebye[a]

[a]*SINTEF Energy Research, Sem Sælands vei 11, Trondheim, Norway*

Abstract

Carbon Capture and Storage (CCS) is an important part of a carbon-constrained energy scenario to reduce global emissions. Most of the present works in literature related to CO_2 capture assumes exhaust stream from power plants, as they represent large CO_2 volume sources, and consider steady flow of exhaust stream to the capture units. However, the feed stream to the CO_2 capture unit from these sources will typically vary over time. As these fluctuations in the exhaust gas profile lead to lower utilization rate of the capture unit, building the CO_2 capture plant for a full capture might not be optimal. Therefore this work evaluates the optimum CO_2 capture unit capacity taking into consideration the trade-off between the cost of capturing CO_2 and paying the emissions cost (quota or tax) for given fluctuating exhaust gas profiles. Costs functions of an amine-based post combustion capture unit for a coal power plant exhaust gas are modelled to represent the cost of capturing CO_2. A Mixed Integer Linear program is formulated and implemented in General Algebraic Modeling System (GAMS) to calculate the economic optimum CO_2 capture plant capacity. The model when applied to a typical fluctuating exhaust gas profile show results indicating significant economic gains in optimizing the installed CO_2 capture capacity. Therefore, in addition to significantly decreasing the cost of CCS on power plants, being able to forecast the fluctuating load on the CO_2 capture unit can also avoid investment delays compared to cases in which only full capacity capture is considered.

Keywords: Carbon Capture and Storage (CCS); Optimal capacity; Techno-economics; CO_2 capture; MILP; Optimization.

1. Introduction

Large-scale decarbonisation of future energy systems is a possible scenario, moving towards more sustainable energy consumption and conversion. Non-renewable fossil fuels account for over 80% of the global total primary energy consumption, and CO_2 emissions from energy use (conversion) amount to

* Corresponding author. Tel.: +47 73593631; fax: +47 73597250.
E-mail address: rahul.anantharaman@sintef.no.

doi:10.1016/j.egypro.2013.06.640

about 60% of global manmade greenhouse gas (GHG) emissions [1]. Carbon Capture and Storage (CCS) is an important part of a carbon-constrained energy scenario to reduce global emissions [2]. The timing and selection of CO_2 sources will affect the cost of achieving projected CCS based emission reductions. Among factors affecting the attractiveness of a particular CO_2 source for CCS, IPCC Special Report on CCS [3] highlight four; (I) CO_2 volume, (II) CO_2 concentration and partial pressure, (III) integrated system aspects and (IV) proximity to suitable reservoir.

Most of the present work in literature related to CO_2 capture assumes flue gas from power plants, as they represent large CO_2 volume sources, and consider steady flow profile of the flue gas. However, the feed stream to the CO_2 capture unit from these sources will typically vary over time. For a load following power plant with CO_2 capture, this flow rate can significantly vary within a day as a function of utility demand. The load on a power plant and thus the CO_2 capture unit will also exhibit fluctuation over the longer time frame such as seasonal variations. For a CO_2 capture unit in an industrial facility (cement, steel, natural gas processing, etc.), the feed to the capture unit is also expected to fluctuate over time. However, the time scale of fluctuations in an industrial CO_2 capture unit will be on a longer time scale than that for a power plant.

As these fluctuations in the exhaust gas profile lead to lower utilization rate of the capture unit, building the CO_2 capture plant for a full capture might not be optimal. This paper evaluates the optimum CO_2 capture unit capacity taking into consideration the trade-off between the cost of capturing CO_2 and paying the emissions cost (quota or tax) for given fluctuating profiles.

2. Techno-economic optimization model

Given a fluctuating flue gas profile, the plant operator has a choice of whether to invest in a CO_2 capture unit or not and if so what should be the capacity of the unit. Further, operationally there are two options:

- capture the CO_2 and incur operating costs (and an initial capital investment cost) or;
- emit the CO_2 and pay for the CO_2 quotas needed to emit it.

The system under consideration incorporating these options is shown in Fig. 1. The flue gas fed from the source can either be sent to the capture unit or emitted to atmosphere (Flue gas Bypass in Fig. 1). The capture unit has a specified capture ratio defined to be the ratio of CO_2 captured to the CO_2 fed to the capture unit. Thus only part of the CO_2 fed to the capture unit is captured and sent to transport and storage. The residual CO_2 is emitted in the Exhaust Gas (see Fig. 1). This is used to set up the CO_2 balance for techno-economic optimization. The total CO_2 emitted is thus the sum of the CO_2 in the Bypass and Exhaust Gas streams.

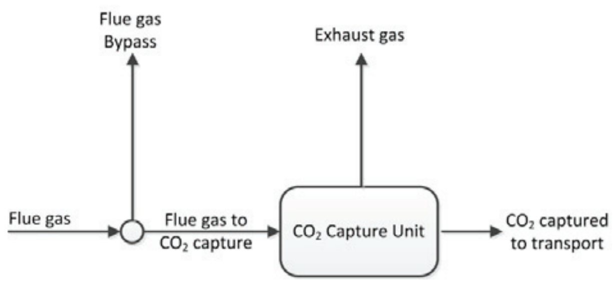

Fig. 1. System boundaries for techno-economic analysis

2.1. Economic model for capture costs

An amine post combustion capture process with 90% capture efficiency, based on Monoethanolamine (MEA) solvent is considered in this study. The investment and operating costs for CCS at different capacities were derived from a 2 $MtCO_2$/y post-combustion capture plant simulation carried out in Aspen Process Economic Analyzer® [4] and subsequent scaling using the equipment cost power law and installation factors for the 1-7 $MtCO_2$/y capacities used in this study. It was assumed the CCS plant received a flue gas with a 13% concentration of CO_2, which is similar to conventional coal fired power plants.

The operating cost is split into fixed and variable operating costs. The fixed operating cost depends on the total investment cost, and covers maintenance, insurance and labour costs. The variable operating cost is a function of the operation load and CO_2 quantities captured. It covers consumption of utilities, electricity, steam, cooling water and MEA make up. Variable costs are assumed to be linear down to 1 $MtCO_2$/y capacity due to parallel construction of main utility consuming units, such as blowers, the stripper and cooler. When a plant doesn't operate at full capacities, some of the parallel units are shut down while the rest operate at full capacity. Therefore it can be assumed that there is no efficiency decreases when a plant doesn't operate at full capacity. However it is assumed that a plant cannot operate under 0.6 Mt/y otherwise the operating condition of the packed columns is overly perturbed.

The annual fixed operating cost is assumed to be 7% of total investment costs, while the annual variable operating cost are estimated using the utilities consumptions given by process simulations and utility costs shown in Table 1. It is worth noting that the steam cost presented in Table 1 is based on extracting steam from the LP steam circuit.

Table 2 shows the functions used to derive Capital, Fixed Operating, and Variable Operating costs.

Table 1: Utilities costs

Utilities	Costs	Units
Electricity [2]	55	€/MWh
Steam prior to LP turbine (5bar 150°C) [1]	3.5	€/GJ
Water [3]	0.02	€/m^3
Pure MEA [4]	1,300	€/t

Table 2: Cost functions for capture process

Function	Costs	Units (y)
y = 58.45x* + 15.24	Capital	(€) Million
y = 4.091x* + 1.067	Fixed Operating	(€) Million/y
y = 15.26x*	Variable Operating	(€) Million/y

*x is the plant's CCS capacity, ranging from 1-7 $MtCO_2$/y

2.2. Model formulation

The objective of the optimization is to maximize the Net Present Value (NPV) of the capture system. The NPV is calculated based on the discounted cash flow method and is given as:

$$NPV = \sum_{t=0}^{n} \frac{Cash\ Flow_t}{(1+i)^t} \quad (1)$$

where $Cash\ Flow_t$ is the cash flow in the year t, i is the yearly discount rate not adjusted for inflation and t is the year number between 0 and n, the project duration.

The cash flow in year t, CF_t, is calculated as:

$$Cash\ Flow_t = -[Capture\ Cost_t \cdot v_t + (CO_2Emitted_t - CO_2Captured_t) \cdot Emission\ Cost] \quad \forall\ t = (1, n) \quad (2)$$

$$Cash\ Flow_0 = -Investment\ Cost \cdot u \quad (3)$$

where $CO_2Emitted_t$ is the total CO_2 emitted in year t ($MtCO_2$), *Emission Cost* is the cost of emitting the CO_2 which is given by the CO_2 quota price (€/tCO_2), and $Capture\ Cost_t$ (M€) is the operating cost of the plant given as the sum of the fixed and variable operating costs described in Section 2.1. $Capture\ Cost_t$ is a function of the CO_2 captured in year t as well as the plant capacity, CO_2Cap_t. *Investment Cost* is the capital investment cost reported to the year 0, i.e. prior to plant operation.

u is a binary decision variable that is set to 1 when the capture unit is installed and 0 when it isn't and v_t is a decision variable that indicates whether the capture unit is switched on/off in year t. u and v_t are related in that $u = 0$ if and only if $v_t = 0$ for all t. If any $v_t = 1$ then $u = 1$.

The CO_2 mass balance around the system (Figure 1) is given by the following equations

$$CO_2\ Flue\ Gas_t = CO_2\ Capture_t + CO_2\ Emitted_t \quad \forall\ t = (1, n) \quad (4)$$

$$CO_2\ Emitted_t = CO_2\ Flue\ Gas\ Bypass_t + CO_2\ Capture\ Unit\ Flow_t \cdot (1 - CO_2\ Capture\ Ratio) \quad \forall\ t = (1, n) \quad (5)$$

$$CO_2Captured_t = CO_2\ Capture\ Unit\ Flow_t \cdot CO_2\ Capture\ Ratio \quad \forall\ t = (1, n) \quad (6)$$

where $CO_2\ Flue\ Gas_t$ is the total CO_2 in the flue gas in year t ($MtCO_2$), $CO_2\ Flue\ Gas\ Bypass_t$ is the total CO_2 in the Flue Gas Bypass that is not captured in year t ($MtCO_2$), $CO_2\ Capture\ Unit\ Flow_t$ is the total CO_2 flow to the capture unit in year t ($MtCO_2$) and $CO_2\ Capture\ Ratio$ is the ratio between CO_2 captured and CO_2 capture unit flow defined by Equation 5.

$CO_2\ Captured_t$ is constrained by the size of the capture unit. This capture unity capacity related constraints are defined in the model as

$$Minimum\ CO_2\ Captured \le CO_2\ Captured_t \le Capture\ Unit\ Capacity \quad \forall\ t = (1, n) \quad (7)$$

$$Capture\ Unit\ Capacity \ge Minimum\ Capture\ Unit\ Capacity \quad (8)$$

where *Capture Unit Capacity* is the CO_2 capture unit capacity ($MtCO_2$/year), $Minimum\ CO_2\ Captured$ is the lowest CO_2 capture possible in the capture unit ($MtCO_2$) and *Minimum Capture Unit Capacity* is the smallest CO_2 capture unit capacity ($MtCO_2$/year). The smallest CO_2 capture unit capacity is defined to be 1 $MtCO_2$/year in this work and subsequently the lowest CO_2 capture possible is 0.6 $MtCO_2$/year. The maximum CO_2 capture unit capacity need not be defined, but would the maximum CO_2 flow rate in the flue gas profile.

The objective function will try make u and v_t to take values 0. Hence we need to include an equation that links a continuous variable, $CO_2\ Captured_t$, to the binary variable, v_t, to ensure it takes a value 1 when CO_2 is captured by the system. The is given by the "big M" constraint below

$$CO_2\ Captured_t - M \cdot v_t \leq 0 \quad \forall\, t = (1, n) \tag{9}$$

where M is set to the maximum CO_2 capture possible for the given variable CO_2 flue gas profile. Equation 9 will ensure that $v_t = 1$ when $CO_2\ Captured_t > 0$.

The techno-economic optimization model to find the optimum capacity is thus formulated as a Mixed Integer Linear Problem (MILP) with Equation 1 as the objective function to be maximized. Equations 2 – 9 are the constraints of the problem. The model is solved in GAMS using CPLEX as the solver.

3. Optimal capacity for fluctuating flue gas profiles

The daily flow profile of the flue gas is shown in Fig. 2 (in blue). The flue gas contains 13.3 vol% CO_2. The CO_2 flow rate is represented by the red bars in Fig 2.

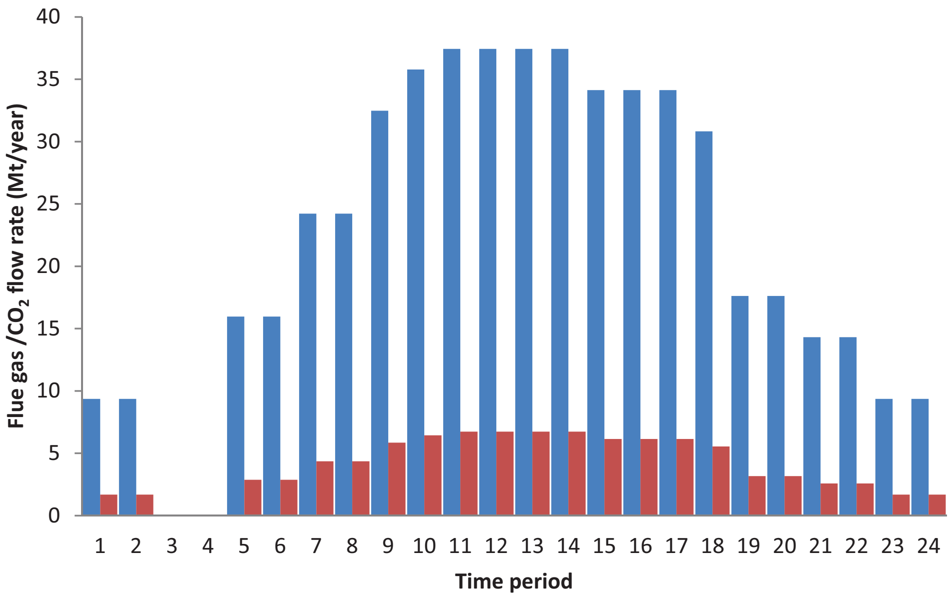

Fig. 2. Daily flow profile of flue gas

The flue gas has a CO_2 concentration of 13.3 vol% and the molar mass of the flue gas is 32.5 kg/kmol. The time period of analysis and lifetime of the capture plant is set to 30 years. The discount rate is assumed to be 8%.

For a given flue gas flow profile, the optimal capacity and CO_2 captured depends on the CO_2 quota price. Figure 3 shows the optimal capacity calculated for a range of CO_2 quota prices from 15 to 80 €/t CO_2.

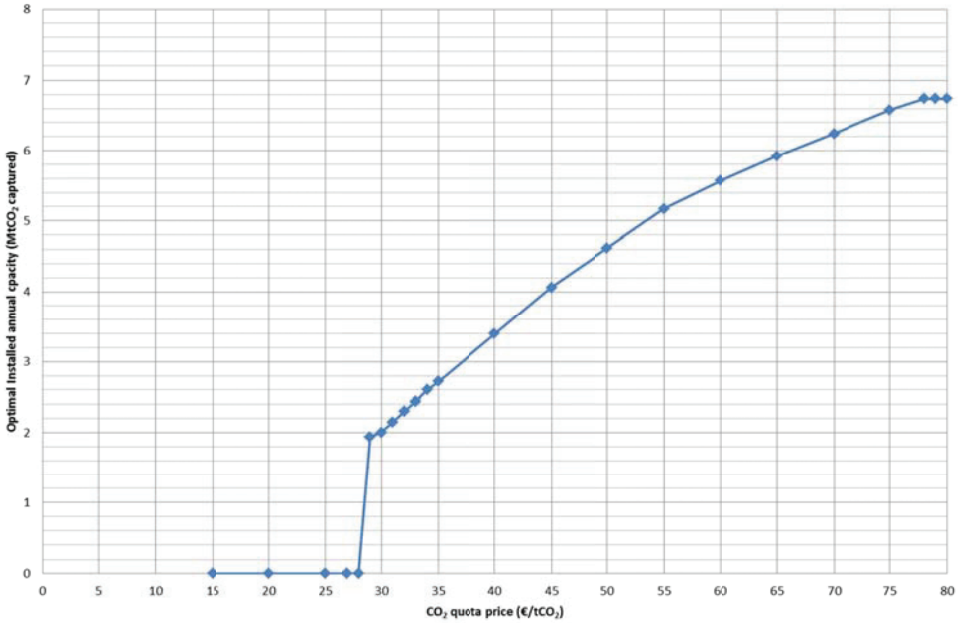

Fig. 3. Optimal capacity as a function of CO_2 quota price

As it can be seen from Fig. 3 and as it can be intuited, at low CO_2 quota price, no CO_2 capture capacity shall be installed. At 29 €/t CO_2 the optimal installed capacity is 1.9 $MtCO_2$ captured/year. This corresponds to the capture break-even price which is the lowest CO_2 emission cost required to equal the cost of a non-null capacity.

The optimal installed capacity steadily increases with increasing quota price until it reaches its maximum capacity value of 6.7 $MtCO_2$ captured/year for an emission cost of 78 €/t CO_2. This correspond to the full capture break-even price which is the lowest CO_2 emission cost for which the cost optimal capacity is maximum CO_2 amount which can be captured from flow in exhaust gas profile.

As it can be seen here, the difference between these two costs is quite significant[†]. Indeed, the full capture break-even price is almost three times the capture break-even price. Therefore one can see the

[†] It is however worth noting that in the case of a constant flow, these two break-even costs and volume are the same.

interest of not capturing at full capacity. A first result of this trend is that industrial actors might make different capture capacity selection depending on their expected CO_2 price and their value for flexibility. Fluctuating production profiles for gas and coal fired power plants could be the case in electricity markets with increased capacity of intermittent renewable production capacity. Another result is that not capturing at full capacity from fluctuating, but at a lower capacity, is less expensive and therefore not capture at full scale may enable a faster development of CCS projects. However this conclusion shall be tempered by the fact that transport and storage, not included here, will also benefit from economies of scale and might decrease the benefit of smaller capture capacities in the case of fluctuating flow.

4. Conclusions

An MILP formulation for the techno-economic optimization for evaluating the optimal CO_2 capture unit capacity for a fluctuating flue gas flow profile has been developed. The model was applied to a typical flue gas profile and the results showed that the profile in accordance with the CO_2 quota price influences whether CO_2 capture unit is installed or not and the optimal installed CO_2 capture unit capacities. Therefore, in addition to significantly decreasing the cost of CCS on power plants, being able to forecast the fluctuating load on the CO_2 capture unit can also avoid investment delays compared to cases in which only full capacity capture is considered.

The results presented here are valid when the CO_2 quota price is kept constant throughout the life time of the unit. Further work should involve, varying the CO_2 quota price over the horizon to include the decision on when to install the CO_2 capture plant in addition to its optimal capacity. Further, coupling this with the electricity prices, the plant operation can be optimized to maximize profit by emitting CO_2 when the electricity price is higher relative to the CO_2 quota price. It is also envisaged that this model could be expanded to study CO_2 chains from multiple sources to multiple sinks.

Acknowledgements

This publication has been produced with support from the BIGCCS Centre, performed under the Norwegian research program Centres for Environment-friendly Energy Research (FME). The authors acknowledge the following partners for their contributions: Aker Solutions, ConocoPhillips, Det Norske Veritas, Gassco, Hydro, Shell, Statoil, TOTAL, GDF SUEZ and the Research Council of Norway (193816/S60).

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